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An implementation of particle swarm optimization to evaluate optimal under-voltage load shedding in competitive electricity markets

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H I G H L I G H T S

- Under-voltage load shedding in a reregulated power system is investigated.
- A technoeconomic multi-objective optimization is proposed.
- Social welfare is considered in the proposed method.
- PSO is utilized for determining an optimal load shedding scheme.
- A significant performance of the proposed method is achieved.

A R T I C L E I N F O

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A B S T R A C T

Load shedding is a crucial issue in power systems especially under restructured electricity environment. Market-driven load shedding in reregulated power systems associated with security as well as reliability is investigated in this paper. A technoeconomic multi-objective function is introduced to reveal an optimal load shedding scheme considering maximum social welfare. The proposed optimization problem includes maximum *GENCO*s and loads' profits as well as maximum loadability limit under normal and contingency conditions. Particle swarm optimization (PSO) as a heuristic optimization technique, is utilized to find an optimal load shedding scheme. In a market-driven structure, generators offer their bidding blocks while the dispatchable loads will bid their price-responsive demands. An independent system operator (ISO) derives a market clearing price (MCP) while rescheduling the amount of generating power in both pre-contingency and post-contingency conditions. The proposed methodology is developed on a 3-bus system and then is applied to a modified IEEE 30-bus test system. The obtained results show the effectiveness of the proposed methodology in implementing the optimal load shedding satisfying social welfare by maintaining voltage stability margin (VSM) through technoeconomic analyses.

1. Introduction

Power systems secure and economic operation in a restructured environment involves: a balance between generation and load, service continuation, stability of power system through social welfare maximization. Any disturbance in a power system like generator or line contingency or a sudden increase in load demand leads to insecure operation while it may cause voltage instability. Voltage stability is considered as the ability of a power system to maintain steady voltages at all load buses under normal operating conditions and after occurring a disturbance [1]. Two well-known methods for maintaining voltage stability are: preventive and corrective actions. Preventive actions are performed based upon pre-contingency state through applying required control strategies to provide a satisfactory security margin. Corrective actions are required when a severe disturbance is imposed on the system and tries to return the system within its security margin. A power system might be in normal, alert, emergency, in extremis and restorative states. Load curtailment can be applied when the system is in the emergency state while load shedding is employed when the system is in extremis state and is driven to collapse [2]. When all other control procedures are unable

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Nomenclature

n_B	number of buses
n_G	number of *GENCO*s
n_{line}	number of lines
n_{load}	number of loads
N_{Gn}	number of generators of n_{th} *GENCO*
λ_i	*LMP* of bus i (\$ MWh^{-1})
a_m,b_m,c_m	generation cost coefficients
α_m,β_m	strategic variables
ρ_m	bidding block price
α_i^k	load importance factor at bus i for load type k
$C_{cong,ij}$	congestion rent of branch ij (\$ h^{-1})
C_{GENCO}	*GENCO*'s cost (\$ h^{-1})
C_{EPNS}	cost of expected power not supplied (\$ h^{-1})
R_{GENCO}	*GENCO*'s revenue (\$ h^{-1})
P_{sys}	maximum loadability limit of system (MW)
n	index of normal state
c	index of contingency state
w	weighting factor
P_{ij}	power flow of line ij (MW)
$P_{G,i}^c$	active power generation in contingency state at bus i (MW)
$P_{D,i}^c$	real power demand in contingency state at bus i (MW)
$\Delta P_{D,i}^c$	amount of load active power shed at bus i (MW)
V_i^c	bus voltage in contingency state at bus i (V)
Y_{ij}	admittance of line ij (Ω)
θ_{ij}	admittance angle of line ij
δ_i^c	voltage angle at bus i in contingency state
$Q_{G,i}^c$	reactive power generation in contingency state at bus i (MVAr)
$Q_{D,i}^c$	load reactive power in contingency state at bus i (MVAr)
$\Delta Q_{D,i}^c$	amount of load reactive power shed at bus i (MVAr)
$P_{G,i}^{\min}$	minimum active power generation at bus i (MW)
$P_{G,i}^{\max}$	maximum active power generation at bus i (MW)
$Q_{G,i}^{\min}$	minimum reactive power generation at bus i (MVAr)
$Q_{G,i}^{\max}$	maximum reactive power generation at bus i (MVAr)
$P_{D,i}^{\min}$	minimum amount of load to be supplied at bus i (MW)
$P_{D,i}^n$	real power demand in normal state at bus i (MW)
S_{ij}^c	apparent power flow of line ij in contingency state (MVA)
$S_{ij}^{\max}$	apparent power limit of line ij (MVA)
$V_i^{\min}$	lower limit of voltage at bus i (V)
$V_i^{\max}$	upper limit of voltage at bus i (V)

to maintain power system security in the case of a disturbance or contingency, optimal load shedding (OLS) will be utilized as the last resort to prevent system blackout [3]. Load shedding (LS) is generally categorized in two well-known methodologies: under-frequency load shedding (UFLS) and under-voltage load shedding (UVLS). UFLS or UVLS is performed when the frequency or voltage falls below a specified threshold. The load shedding procedure cuts a particular amount of load in such a manner that a balance between generation and demand is achieved resulting in a widespread system blackout prevention [4]. The main factors in load shedding are: location, amount, and time of load cut. On the other hand, to prevent post-contingency problems, the location of the proposed buses for load shedding must be determined based upon the load importance, curtailment cost and the distance of the curtailed load to the contingency location [5].

Load shedding implementation can be categorized into three main procedures [6–9]. The first procedure involves shedding a fixed amount of load which is similar to UFLS [10]. This procedure involves time simulation analysis and studying instability from dynamic aspects of a power system while a drawback of such approach is integrating a time domain simulation to an optimization problem [11]. The second approach considers shedding an amount of load with dynamic characteristics which involves a precise modeling of dynamic load parameters. The third approach utilizes optimal power flow (OPF) equations of a power system static model to determine the minimum load shedding. Since the dynamics associated with voltage stability are often slow, a static approach proposes a good approximation of system voltage stability. The fundamental idea of such approach is finding a feasible solution to the power flow equations [12,13]. Load shedding considering static model of a power system is addressed in former researches and is solved using different mathematical techniques such as linear programming (LP), nonlinear programming, and interior point method [14–16]. In some other studies, evolutionary algorithms such as genetic algorithm (GA) [17], particle swarm optimization (PSO) [6–9], and ant colony optimization (ACO) [18] have been utilized to tackle the load shedding problem. The advantage of the evolutionary algorithms is their accuracy in obtaining feasible solution while considering problem constraints. In Ref. [9], an approach for UVLS is presented based upon a dynamic security-constrained OPF utilizing PSO. It is aimed to provide sufficient voltage stability margin for post-contingency condition. Load shedding as a solution for congestion management along with generation rescheduling is presented in Ref. [19], where a multi-objective PSO method is suggested to solve such a complex nonlinear problem. Minimum load shedding has been developed using conventional PSO and coordinated aggregation based PSO (CAPSO) in Ref. [20]. The previous studies have conducted the optimal load shedding in a regulated market environment where no competition is considered for market participants.

However, in the reregulated power market, beside the secure operation as the main purpose, the profit of market participants such as: *GENCO*s, TRANSCO and customers should be maximized. In fact, the role of ISO is to maximize social welfare through optimizing all participants' profit considering operational constraints. In a market-driven environment, the locational marginal prices (*LMP*s) are determined according to the *GENCO*s' offers and real power losses as well as lines congestion. When a generator contingency occurs, *GENCO*s are obliged to pay the penalty of load shedding which is in terms of expected power not supplied (*EPNS*). On the other hand, congestion influence on market clearing price (MCP) which may lead to locational marginal price (*LMP*) differences. Congestion rent is defined as the difference of *LMP*s multiplied by the power flow through a congested line [21–23].

This paper addresses a steady state load shedding scheme where a multi-objective function to optimize a technoeconomic model in a restructured power system environment is considered. In the proposed methodology, an optimal load shedding is handled through optimizing technoeconomic social welfare including: *GENCO*s and customers profits, congestion rent, and loadability limit. Here, the smart market procedure is utilized where the ISO as the market authority receives *GENCO*s' offers and dispatchable loads bidding blocks to establish the market clearing price and to determine the generating pattern as well as the participation amount of dispatchable loads. In the proposed scheme when a contingency occurs, the minimum load shed that may guarantee the social welfare will be obtained.

The rest of this paper is organized as follows. Section 2 elaborates a framework of the proposed scheme through a 3-bus system.

The proposed formulation is explained in details in Section 3 while Section 4 describes the solution methodology. Section 5 conducts the simulation studies and results analysis of applying the methodology to a modified IEEE 30-bus test system. Finally, concluding remarks are drawn in Section 6.

2. Framework of the proposed scheme

2.1. Smart market environment

The smart market virtually performs the ISO role in a restructured environment to handle the generators offers and dispatchable loads bids for determining *LMP*s. In a smart pool-based market, both *GENCO*s and dispatchable loads as price-responsive loads propose their bidding blocks to the power pool. If n_{th} *GENCO* has N_{Gn} generators with the following second-order operating cost function:

$$C_m = C(P_{G,m}) = a_m P_{G,m}^2 + b_m P_{G,m} + c_m \ \forall m = 1,2,\ldots,N_{Gn} \tag{1}$$

Then its marginal cost is:

$$\lambda_m = 2a_m P_{G,m} + b_m \tag{2}$$

It is assumed that a *GENCO* submit its generating bids not necessarily identical to its marginal costs by a convex quadratic function that resembles Eq. (1) [24,25].

$$f(P_{G,m}) = \alpha_m P_{G,m}^2 + \beta_m P_{G,m} \tag{3}$$

Then, each *GENCO* submits its generating bidding blocks to the ISO utilizing the simple linear supply function as:

$$\rho_m = \zeta_m \times \frac{\partial f(P_{G,m})}{\partial P_{G,m}} = \zeta_m \times (2a_m P_{G,m} + b_m) \tag{4}$$

The smart market is based on double-side auctions where the *GENCOs*' offers are ranked in an ascending order while the dispatchable loads' bids are arranged in a descending order. The market clearing mechanism in the smart market environment of MATPOWER 4.1 is accomplished by merit order dispatch. In an efficient power market, an equal quantity of each block is accepted, beginning with the lowest offers and highest bids. This procedure will be terminated when supply or demand is depleted or the offer price exceeds the bid price. In such clearing scheme, the last accepted bid (LAB) will be greater than the last accepted offer (LAO) which leaves a bid-offer gap. A uniform price set to anything within such bid-offer gap will be satisfactory for all buyers and sellers [26–28]. The procedure of double-side auction in a smart market environment is illustrated in Fig. 1.

In general when a contingency occurs, it is common to shed the fixed loads in order to maintain the security of a power system. However, in a smart market environment, three types of loads from economic viewpoint can be considered: fixed loads, flexible loads, and price-responsive dispatchable loads. Flexible loads can be curtailed through an advance notice from ISO when needed while dispatchable loads are cut pricewise. In a market-based load shedding scheme, although ordinary load shedding maintains security, the dispatchable loads may not be removed even in the emergency state of a power system.

2.2. Market-based load shedding pricing scheme

When an outage occurs in a power system, due to insufficient transmission capacity, congestion rent may increase. By executing

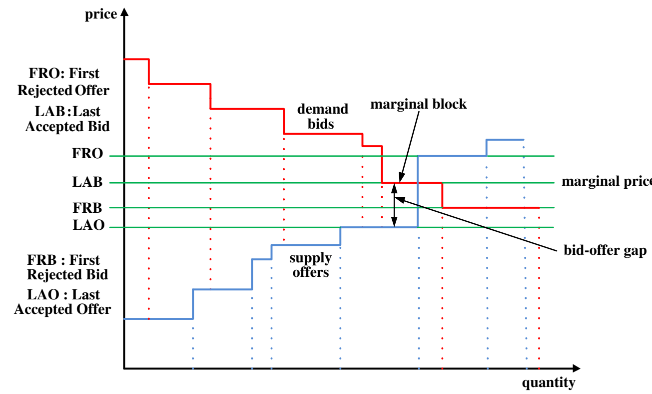

Fig. 1. Double-side auction in smart market structure [27].

market-based load shedding, any *GENCO* subjected to its generators outage is obliged to pay *EPNS* costs as a penalty of load shedding. On the other hand, ISO is responsible for *EPNS* costs of a line contingency. The *EPNS* cost compensation is formulated by Eq. (5):

$$\gamma_\psi = \begin{cases} 1 & \text{Generator contingency} & \forall \psi \triangleq m : 1,2,\ldots,N_{Gn} \\ 0 & \text{otherwise} & \\ 1 & \text{Line contingency} & \forall \psi \triangleq L : 1,2,\ldots,n_{line} \end{cases} \tag{5}$$

where $\sum \gamma_\psi = 1 \quad \forall \psi \in \{m, L\}$ (single contingency).

EPNS costs are determined by multiplying MW shed and load shedding marginal price (*LSMP*) as shown by Eq. (6).

$$LSMP_i^k = \alpha_i^k LMP_i^k \tag{6}$$

where: α_i^k is a multiplier as the load importance factor (LIF) dependent on the type k and location i of each individual load.

Therefore, *LSMP* of more important loads has a higher value which is an economic signal to ISO to prevent high penalty load shedding.

In order to investigate load shedding under a smart market environment, a simple 3-bus system as shown in Fig. 2 is considered. The line data of 3-bus system is provided in Table 1, where it includes a slack generator with a maximum generation capacity of 350 MW at bus 1 belonging to *GENCO* #1, a generator with a maximum generation capacity of 150 MW belonging to *GENCO* #2, a fixed load at bus 2, and a fixed and a dispatchable load at bus 3. The *GENCOs*' offers are shown in Table 2, while the dispatchable

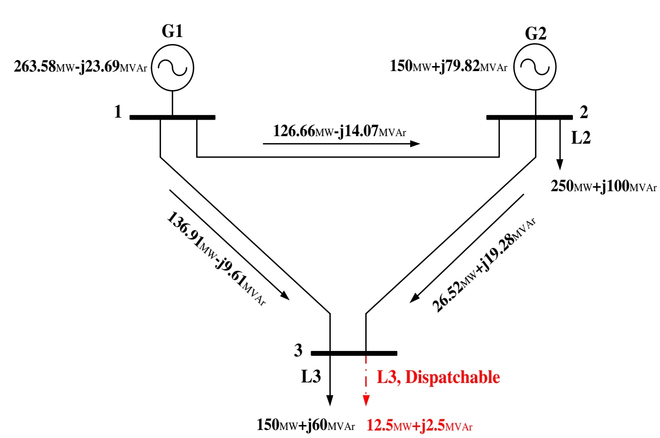

Fig. 2. Three-bus system in normal operating condition.

Table 1
Three-bus system line data.

Line	Impedance
1–2	0.01 + j0.1
1–3	0.05 + j0.1
2–3	0.05 + j0.1

Table 2
Generators offers.

Generator 1		Generator 2	
Quantity (MW)	Price (\$ MWh^{-1})	Quantity (MW)	Price (\$ MWh^{-1})
50	40	20	30
75	50	30	40
100	60	40	50
125	80	60	70

load is a 50 MW load divided into 4 equal blocks of 12.5 MW with prices of 100 \$ MWh^{-1}, 70 \$ MWh^{-1}, 60 \$ MWh^{-1}, and 40 \$ MWh^{-1}, respectively.

2.2.1. Normal state

In a normal operating condition, ISO determines *LMP*s based on *GENCOs*' offers through optimal power flow, where the *LMP*s of buses 1–3 are 80 \$ MWh^{-1}, 80.393 \$ MWh^{-1}, and 80.798 \$ MWh^{-1}, respectively. Based upon the smart market calculation, only the first 12.5 MW block of the dispatchable load is cleared with a price 80.8251 \$ MWh^{-1}. Here, the revenue and cost of *GENCO* #1 are 21086.34 \$ h^{-1} and 7210.98 \$ h^{-1} respectively resulting a profit 13875.36 \$ h^{-1}. Similarly the revenue and cost of *GENCO* #2 are 12059.05 \$ h^{-1} and 7050.05 \$ h^{-1} respectively leading to a profit 5009 \$ h^{-1}. The revenue and cost of dispatchable load is 1250 \$ h^{-1} and 1010.31 \$ h^{-1} respectively providing a profit 239.69 \$ h^{-1}, while the congestion rent is 169 \$ h^{-1}.

2.2.2. Contingency state

As a consequence of generator #2 outage (Fig. 3), load shedding is performed. It is assumed that load importance factor for buses 1–3 are 4, 3, and 1.5, respectively. The lower LIF implies that the corresponding load is more disposable to be curtailed.

Since generator #1 has 350 MW generation capacity, some MW of load will be shed, which are: 23.9 MW at bus 2 and 40.9 MW at bus 3. The *LMP*s are 80.021 \$ MWh^{-1}, 80.650 \$ MWh^{-1}, and 80.786 \$ MWh^{-1} for buses 1–3, respectively. In this condition, the dispatchable load is not curtailed because of higher *LSMP* in comparison with the *LMP* at bus 3. Since 12.5 MW of dispatchable load with price 70 \$ MWh^{-1} is cleared, and the *LSMP* at bus 3 is 105 \$ MWh^{-1}, it is worthy curtail the fixed load. This fact can be considered as a consequence of market-based load shedding scheme. Here, the revenue of *GENCO* #1 is 27932.71 \$ h^{-1} while its cost is 12540.35 \$ h^{-1} with the profit 15392.36 \$ h^{-1}. On the other hand, revenue and cost of dispatchable load is 1250.1 \$ h^{-1} and 875.07 \$ h^{-1}, respectively which leads to a profit 375.03 \$ h^{-1}. The 135.24 \$ h^{-1} decrease in the cost of dispatchable load is due to the decrement of *LMP* at bus 3 as a result of load shedding. The congestion rent increases to 243.564 \$ h^{-1} which implies an increment 74.564 \$ h^{-1}, while *EPNS* cost is 4974.5 \$ h^{-1}.

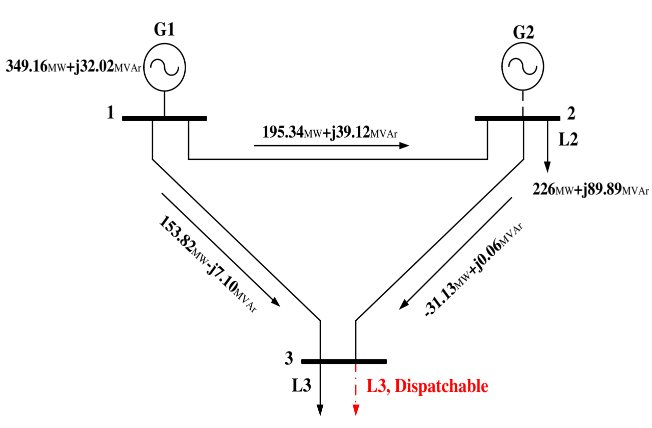

Fig. 3. Three-bus system after G2 contingency.

2.3. Loadability limit calculation

Practically in a large-scale power system, voltage stability must be considered to guarantee power system security. Loadability limit is an index of voltage security margin (VSM) that generally can be calculated using continuation power flow (CPF). CPF is a powerful algorithm to trace the power flow solution, starting at a base load leading up to the steady state voltage stability limit, for determining loadability limit. Since the continuation power flow is time-consuming for large-scale power systems, online application require faster tools like neural networks [29].

3. Mathematical problem formulation

In a market-based environment, ISO aims to maximize social welfare while maintaining system security. Therefore, a technoeconomic multi-objective optimization problem comprised four terms is considered. The first term is *GENCO*'s maximum profit which is formulated by Eq. (7). The second term is loads' maximum profit in both normal and contingency conditions which is formulated by Eq. (8). Minimizing congestion rent as well as *EPNS* costs related to a line contingency as third term is expressed in Eq. (9). Maximizing system loadability is the final term that is expressed by Eq. (10):

$$f_1 = \sum_{i=1}^{n_G} R_{GENCO} - \sum_{i=1}^{n_G} C_{GENCO} - \sum_{i=1}^{n_B} \gamma_\psi C_{EPNS} \;\; \forall \psi \in \{m\} \tag{7}$$

$$f_2 = \sum_{1}^{n_{load}} \left(LSMP \times P^c_{D,i} - LMP \times P^n_{D,i} \right) \tag{8}$$

$$f_3 = -\left(\sum_{\substack{i=1 \\ i \neq j}}^{n_B} C_{cong,ij} + \sum_{i=1}^{n_B} \gamma_\psi C_{EPNS} \right) \quad \forall \psi \in \{L\} \tag{9}$$

where $C_{cong,ij} = \sum_{i \neq j}^{n_B} (\lambda_i - \lambda_j) P_{ij}, \quad P_{ij} \geq 0$

$$f_4 = P_{sys} \tag{10}$$

The combinatorial objective function can be formulated as follows:

$$Maximize \left\{ \sum w_i \frac{f_i}{f_i^{\max}} \right\}, \quad \forall i = 1, \ldots, 4 \tag{11}$$

where: w_1 to w_4 can be tuned using the expert knowledge. $f_1^{\max}$ is the *GENCO*'s maximum achievable profit. $f_2^{\max}$ is the maximum attainable loads' profit. Minimum amount of congestion rent and *EPNS* costs related to a line contingency is expressed by $f_3^{\max}$ and

finally $f_4^{\max}$ is maximum affordable loadability limit. Operating constraints of such optimization problem are as follows:

$$P_{G,i}^{c} - \left(P_{D,i}^{c} - \Delta P_{D,i}^{c}\right) = \sum_{i=1}^{n_B} |V_i^c| \cdot \left|V_j^c\right| \cdot |Y_{ij}| \cdot Cos\left(\theta_{ij} - \delta_i^c + \delta_j^c\right) \tag{12}$$

$$Q_{G,i}^{c} - \left(Q_{D,i}^{c} - \Delta Q_{D,i}^{c}\right) = -\sum_{i=1}^{n_B} |V_i^c| \cdot \left|V_j^c\right| \cdot |Y_{ij}| \cdot Sin\left(\theta_{ij} - \delta_i^c + \delta_j^c\right) \tag{13}$$

$$P_{G,i}^{\min} \le P_{G,i}^{c} \le P_{G,i}^{\max} \tag{14}$$

$$Q_{G,i}^{\min} \le Q_{G,i}^{c} \le Q_{G,i}^{\max} \tag{15}$$

$$P_{D,i}^{\min} \le P_{D,i}^{c} \le P_{D,i}^{n} \tag{16}$$

$$\left|S_{ij}^{c}\right| \le \left|S_{ij}^{\max}\right| \tag{17}$$

$$\left|V_i^{\min}\right| \le |V_i^c| \le |V_i^{\max}| \tag{18}$$

The amount of load shedding is restricted between its pre-contingency value and its prescribed minimum amount; $P_{D,i}^{\min}$ Eq. (16). Therefore, the maximum amount of load shedding at bus i is $(P_{D,i}^{c} \le P_{D,i}^{n} - P_{D,i}^{\min})$.

4. Solution methodology

In order to solve such a complicated optimization problem for determining the optimal amount of load shed at each individual bus especially in the presence of contingency, particle swarm optimization (PSO) is utilized. PSO algorithm is initialized by generating a population of random solutions, the so-called a swarm. Positions (*x*,*y*) and velocities (*vx* and *vy*) of each agent represents the modification of each agent's new position. Each agent knows its best value (*pbest*) and its (*x*,*y*) position so far. Moreover, each agent knows the best value so far in the group (*gbest*) among *pbests*. Each agent tries to modify its position using the following information: The current positions (*x*,*y*), the current velocities (*vx*,*vy*), the distance between the current position and *pbest*, and the distance between the current position and *gbest* [30]. In a *D*-dimensional search space, the position of m_{th} agent can be represented by a vector $s_m = (s_{m1},...,s_{md},...,s_{mn})$ and the velocity of m_{th} agent can be proposed by a vector $v_m = (v_{m1},...,v_{md},...,v_{mn})$. The best previous experience of m_{th} agent is proposed by $pbest_m = (pbest_{m1},...,pbest_{md},...,pbest_{mn})$ and the best value among all agents experiences in the group is stored in $gbest_m = (gbest_{m1},...,gbest_{md},...,gbest_{mn})$. Velocity of each agent can be modified by Eq. (19):

$$v_{md}^{k+1} = \omega\, v_{md}^{k} + c_1 rand_1 \times \left(pbest_{md} - s_{md}^{k}\right) + c_2 rand_2 \times \left(gbest_d - s_{md}^{k}\right) \tag{19}$$

where: v_m^k is velocity of agent m at iteration k, ω is weighting function, c_1 and c_2 are weighting coefficients, *rand* is a random number between 0 and 1, s_m^k is the current position of agent m at iteration k, $pbest_m$ is *pbest* of agent *m*, and *gbest* is *gbest* of the group. c_1 and c_2 try to pull each agent towards *pbest* and *gbest* position [7]. According to the early experiences [31], c_1 and c_2 are often set to 2.0 which is also applicable to power system optimization problems. Velocity of an agent that is usually limited to a certain maximum value can be changed using three vectors. The first term in right hand side of Eq. (19) corresponds to *diversification* in the search procedure while the second and third terms correspond to *intensification* in the search procedure.

The new position of agent *m* considering its current position can be determined using the following equation:

$$s_{md}^{k+1} = s_{md}^{k} + v_{md}^{k+1} \tag{20}$$

The weighting function ω is obtained from Eq. (21) and is utilized in PSO algorithm to improve its performance through providing a balance between global and local explorations. This leads to averagely less iterations to obtain a sufficiently optimal solution.

$$\omega^{k+1} = \omega^{\max} - \frac{\omega^{\max} - \omega^{\min}}{iter_{\max}} \times iter \tag{21}$$

where: $\omega^{\max}$ is initial weight, $\omega^{\min}$ is final weight, $iter_{\max}$ is maximum iteration number, and *iter* is current iteration number. Such PSO algorithm that uses Eqs. (19) and (21), is called inertia weights approach (IWA). As generally developed, $\omega^{\max}$ and $\omega^{\min}$ are set to 0.9 and 0.4 respectively. Therefore, at the beginning of the search procedure, *diversification* is heavily weighted, while *intensification* is heavily weighted at the end of the search procedure. Namely, a certain velocity, which gradually gets close to *pbest* and *gbest* can be calculated. The advantages of PSO over other algorithms are lower sensitivity to the nature of the objective function of an optimization problem, derivative-free characteristic unlike many conventional techniques, easy implement ation, etc.

The flow diagram of the proposed methodology for optimal load shedding through PSO algorithm is presented in Fig. 4. The system initial data, generators offers, and dispatchable loads bids for an AC smart market environment are provided. Generating output associated with the price of each generator as well as MW and price of dispatchable loads are calculated through performing smart market procedure of MATPOWER 4.1. On the other hand, maximum loadability limit is determined through CPF. In the case of any generator or line contingency, PSO determines the optimal load shedding which would provide maximum technoeconomic social welfare through Eqs. (7)–(10). In the proposed PSO algorithm, the control variables which define the dimensions of an agent include the load shedding at load buses. It is assumed the load shedding at each bus is limited up to 50% of its demand, which implies $P_{D,i}^{\min} = 0.5P_{D,i}^{n}$. The power market participants' revenues and costs are calculated through smart market environment using the data obtained from PSO including the remained MW of fixed and dispatchable loads. Generation rescheduling considering physical constraints incorporating line thermal capacity is performed through an interior OPF procedure in smart market environment.

A modified IEEE 30-bus test system shown in Fig. 5 is considered as a case study to evaluate the effectiveness of the proposed method. The system includes three areas while its initial operating conditions are shown in Table 3. In order to handle load shedding contribution three load importance factors (LIFs) in areas 1–3 are assumed $\alpha_i^1 = 2$, $\alpha_i^2 = 1.7$, $\alpha_i^3 = 1.3$, respectively. The system has also three 30 MW dispatchable loads at buses 7, 15, and 30. When a contingency occurs, such price-responsive loads may be fully or partially removed or remained according to the *LMP*s. In the following, the proposed methodology is investigated under different conditions.

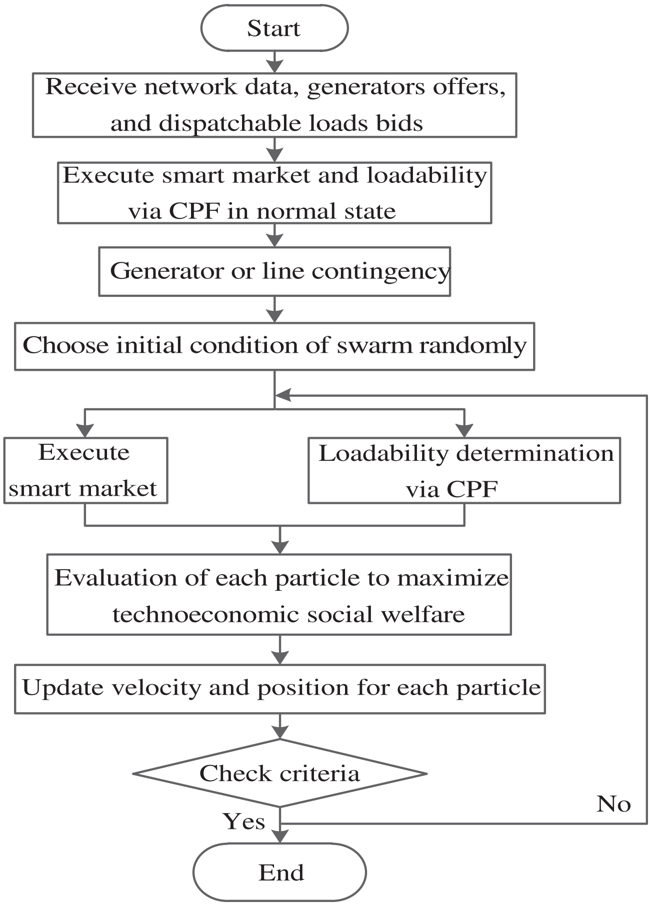

Fig. 4. Solution methodology flow diagram.

Table 3
Initial operating condition of the system.

Bus no.	Voltage magnitude	Fixed loads demands		Generation power	
	V_i (pu)	$P_{D,i}$ (MW)	$Q_{D,i}$ (MVAr)	$P_{G,i}$ (MW)	$Q_{G,i}$ (MVAr)
1	1.041	ss	0	28.25	2.85
2	1.039	5.0448	2.952	48.78	7.57
3	1.021	22.318	11.159	0.00	0.00
4	1.023	8.834	1.859	0.00	0.00
5	1.027	0	0	0.00	0.00
6	1.025	0	0	0.00	0.00
7	1.014	0	0	0.00	0.00
8	1.020	13.948	13.948	0.00	0.00
9	1.037	0	0	0.00	0.00
10	1.043	6.741	2.324	0.00	0.00
11	1.037	0	0	0.00	0.00
12	1.023	13.018	8.718	0.00	0.00
13	1.059	0	0	43.89	23.72
14	1.008	7.2069	1.859	0.00	0.00
15	1.005	0	0	0.00	0.00
16	0.991	4.068	2.092	0.00	0.00
17	0.969	10.461	6.741	0.00	0.00
18	0.971	3.7197	1.046	0.00	0.00
19	0.956	11.042	3.952	0.00	0.00
20	0.955	2.557	0.813	0.00	0.00
21	1.05	3.390	2.169	0.00	0.00
22	1.052	0	0	25.91	17.85
23	1.028	22.318	11.159	23.04	20.85
24	1.032	10.112	7.788	0.00	0.00
25	1.049	0	0	0.00	0.00
26	1.030	4.068	2.673	0.00	0.00
27	1.070	0	0	32.29	19.33
28	1.030	0	0	0.00	0.00
29	1.05	2.789	1.046	0.00	0.00
30	1.039	0	0	0.00	0.00
Total	–	151.64	82.306	202.16	97.16

5. Simulation studies and results discussions

5.1. Normal operating conditions

In the normal operating conditions, by performing smart market procedure considering the dispatchable loads bidding blocks presented in Table 4, the total remained MW of dispatchable loads is

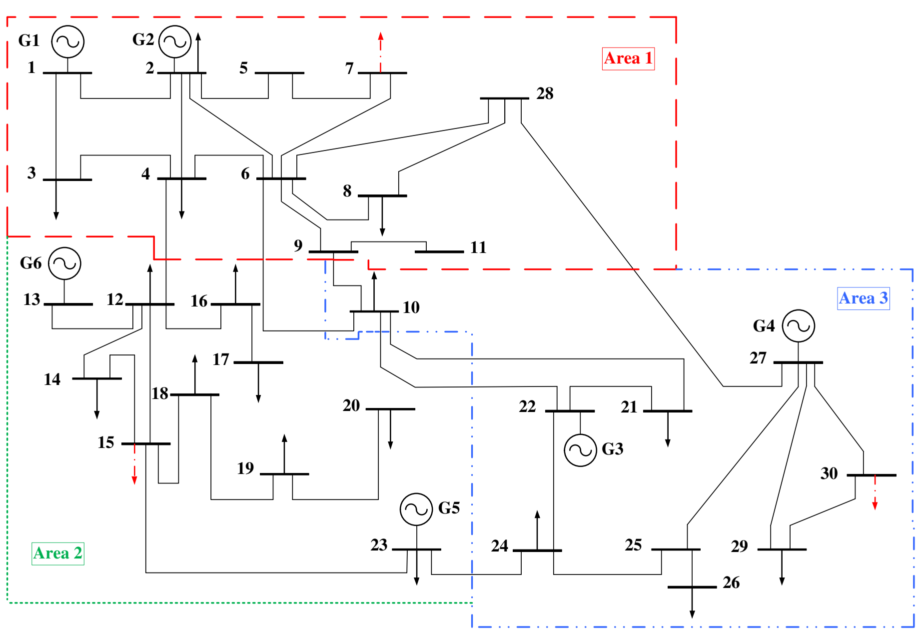

Fig. 5. Modified IEEE 30-bus test system [32].

Table 4
Dispatchable loads status in the normal condition.

Load (Bus #)	Dispatched/Offered prices and quantities					
	Block 1		Block 2		Block 3	
	MW	$ MWh^{-1}	MW	$ MWh^{-1}	MW	$ MWh^{-1}
1 (7)	10	60	10	60	7.3	60
	10	100	10	70	10	60
2 (15)	10	72.880	0	–	0	–
	10	100	10	50	10	20
3 (30)	10	62.685	0	–	0	–
	10	100	10	60	10	50

47.3 MW. The total 198.9 MW load that will be served in the normal operating conditions is the sum of 151.6 MW; as fixed loads; and the remained dispatchable loads. In the normal operating conditions, *GENCO* #1 revenue as the owner of generators 1 and 2 in area 1 is 6024.74 $ h^{-1} while its cost is 2728.72 $ h^{-1} tends to a profit 3296.02 $ h^{-1}. The revenue and cost of dispatchable load at bus 7 in area 1 are 2729.54 $ h^{-1} and 1637.72 $ h^{-1} respectively revealing a profit 1091.82 $ h^{-1}. The revenue of *GENCO* #2 as the owner of generators 5 and 6 in area 2 is 4749.56 $ h^{-1} while its cost is 2276.25 $ h^{-1} leads to a profit 2473.31 $ h^{-1}. The revenue and cost of dispatchable load at bus 15 in area 2 are 1000 $ h^{-1} and 728.81 $ h^{-1} respectively and its profit is 271.19 $ h^{-1}. The revenue of *GENCO* #3 as the owner of generators 3 and 4 in area 3 is 3522.23 $ h^{-1} while its cost is 1847.96 $ h^{-1} leading to a profit 1674.27 $ h^{-1}. The revenue and cost of dispatchable load at bus 30 in area 3 are 1000 $ h^{-1} and 626.86 $ h^{-1} respectively which leads to a profit 373.14 $ h^{-1}. The total congestion rent in the whole market is 566.292 $ h^{-1}. In the normal operating condition maximum loadability limit is 561.643 MW. In such conditions, assuming no dispatchable load, the revenue and cost of *GENCO* #1 are 1994.41 $ h^{-1} and 889.94 $ h^{-1} respectively which reveals a profit 1104.47 $ h^{-1}. A decrease in the profit of *GENCO* #1 is due to the decommitment of generator 2. The revenue and cost of *GENCO* #2 are 4853.15 $ h^{-1} and 2287.62 $ h^{-1} respectively which leads to a profit 2565.53 $ h^{-1}. The revenue and cost of *GENCO* #3 are 4081.49 $ h^{-1} and 1847.96 $ h^{-1} respectively which reveals a profit 2233.53 $ h^{-1}. Congestion rent is decreased to 251.325 $ h^{-1}, while maximum loadability limit under such assumption decreases to 491.643 MW.

5.2. Line contingency in line 2–4

Considering the pre-contingency condition and from smart market AC-OPF results, maximum power flow 50.65 MVA transmits through line 12–13. Since this line is the only connection between G6 and the rest of the system, an outage in line 12–13 causes G6 islanding that leads to anomalous 30 times increase in *LMP*s as it is emphasized in Ref. [33]. Since such islanding may lead to a widespread blackout in the system, the second worst contingency is line 2–4 outage with maximum 19.68 MVA transmitted power. Such an outage also causes overloadings in lines 2–6 and 4–6. In the case of contingency in line 2–4, the proposed algorithm reveals the minimum load shedding that maximizes multi-objective technoeconomic social welfare optimization problem. By assuming equal values for w_1, w_2, w_3 and w_4 as 0.25, the revenue and cost of *GENCO* #1 are 5821.01 $ h^{-1} and 2728.72 $ h^{-1} respectively with a profit 3092.29 $ h^{-1}. The revenue and cost of *GENCO* #2 are 3352.31 $ h^{-1} and 1625.6 $ h^{-1} respectively with a profit 1726.71 $ h^{-1}. The revenue and cost of *GENCO* #3 are 2636.95 $ h^{-1} and 1417.36 $ h^{-1} respectively leading to a profit 1219.59 $ h^{-1}. The congestion rent is 223.964 $ h^{-1} while *EPNS* cost is 1505 $ h^{-1}. Here 50 MW of dispatchable loads is selected where the details are shown in Table 5. The revenue and cost of

Table 5
Dispatchable loads status in the case of line 2–4 contingency.

Load (Bus #)	Dispatched/Offered prices and quantities					
	Block 1		Block 2		Block 3	
	MW	$ MWh^{-1}	MW	$ MWh^{-1}	MW	$ MWh^{-1}
1 (7)	10	52.998	10	52.998	10	52.998
	10	100	10	70	10	60
2 (15)	10	53.781	0	–	0	–
	10	100	10	50	10	20
3 (30)	10	54.679	0	–	0	–
	10	100	10	60	10	50

dispatchable load at bus 7 in area 1 are 3000 $ h^{-1} and 1589.95 $ h^{-1} with a profit 1410.05 $ h^{-1}. The revenue and cost of dispatchable load at bus 15 in area 2 are 1000 $ h^{-1} and 537.82 $ h^{-1} respectively which leads to a profit 462.18 $ h^{-1}. The revenue and cost of dispatchable load at bus 30 in area 3 are 1001.53 $ h^{-1} and 547.63 $ h^{-1} respectively while its profit is 453.9 $ h^{-1}. Minimum total load shedding that satisfies the optimal solution is 26.745 MW, where the details are presented in Table 6 and maximum loadability limit is 534.898 MW. Load cut at each bus of modified IEEE 30-bus test system in the case of line 2–4 contingency is demonstrated in Fig. 6.

5.3. Generator contingency in G2

According to the pre-contingency operating conditions by executing smart market OPF, generator G2 produces 48.78 MW out of total generation 202.16 MW. It can be said that the worst contingency is G2 outage. By performing a multi-objective

Table 6
Load cuts in the case of line 2–4 contingency.

Bus no.	Fixed loads demands before contingency	Fixed loads shed after contingency	
	$P_{D,i}$ (MW)	Load shed (MW)	Load shed (initial load) (%)
1	0	0	–
2	5.0448	0	0
3	22.318	0	0
4	8.834	0	0
5	0	0	–
6	0	0	–
7	0	0	–
8	13.948	0	0
9	0	0	–
10	6.741	0	0
11	0	0	–
12	13.018	0.1714	1.31
13	0	0	–
14	7.2069	3.6034	50
15	0	0	–
16	4.068	2.0342	50
17	10.461	5.2308	50
18	3.7197	1.8581	49.9
19	11.042	5.5191	49.9
20	2.557	1.2786	50
21	3.390	0.0022	0. 06
22	0	0	–
23	22.318	6.2487	27.9
24	10.112	0	0
25	0	0	–
26	4.068	0.7657	18.8
27	0	0	–
28	0	0	–
29	2.789	0.03292	1.18
30	0	0	–
Total	151.643	26.745	17.6

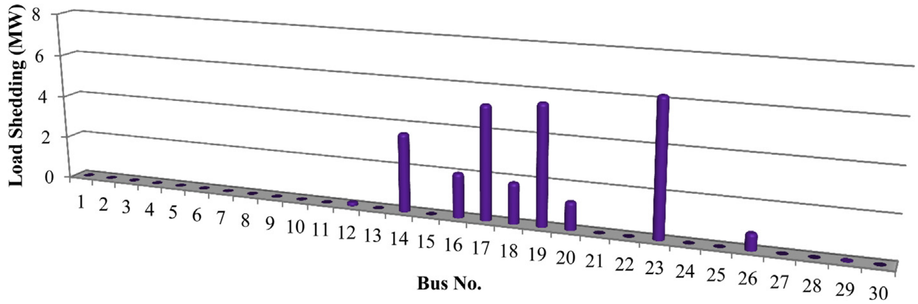

Fig. 6. Load cut at each bus of modified IEEE 30-bus test system in the case of line 2–4 contingency.

Table 7
Load cuts in the case of G2 contingency.

Bus no.	Fixed loads data before contingency		Fixed loads shedding after contingency		
	$P_{D,i}$ (MW)	*LMP* before contingency (\$ MWh^{-1})	Load shed (MW)	Load shed (initial load) (%)	*LMP* after contingency (\$ MWh^{-1})
1	0	57.877	0	–	70.973
2	6.0538	58.029	1.1649	19.24	71.347
3	26.7818	59.044	0	–	71.932
4	10.6011	59.027	0.4523	4.26	71.758
5	0	58.918	0	–	71.433
6	0	59.352	0	–	71.574
7	0	59.782	0	–	71.521
8	16.7386	59.492	0	–	71.711
9	0	60.307	0	–	71.762
10	8.0903	60.799	0	–	71.860
11	0	60.307	0	–	71.762
12	15.6227	72.000	4.8042	30.75	72.000
13	0	72.000	0	–	72.000
14	8.6483	72.830	2.6926	31.13	73.073
15	0	72.591	0	–	73.173
16	4.8821	73.992	2.4410	50	73.078
17	12.5540	75.385	6.2770	50	73.798
18	4.4636	75.708	0.6078	13.61	75.104
19	13.2514	77.151	6.6257	50	75.852
20	3.0687	77.290	1.5343	50	75.924
21	4.0684	60.911	1.6746	41.16	71.537
22	0	60.931	0	–	71.396
23	26.7818	68.978	1.1231	4.19	73.263
24	12.1355	64.426	0	–	72.914
25	0	62.059	0	–	71.627
26	4.8821	63.279	0.04027	0.82	73.367
27	0	60.191	0	–	70.225
28	0	59.356	0	–	71.171
29	3.3477	61.558	0	–	70.812
30	0	62.542	0	–	70.418
Total	181.972	–	29.438	16.17	–

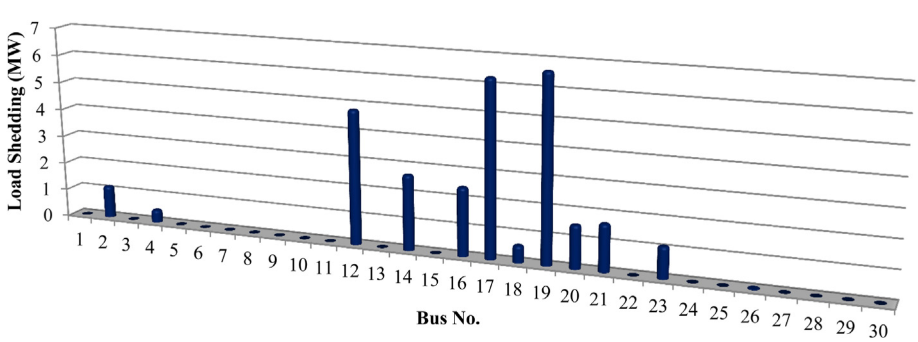

Fig. 7. Load cut at each bus of modified IEEE 30-bus test system in the case of G2 contingency.

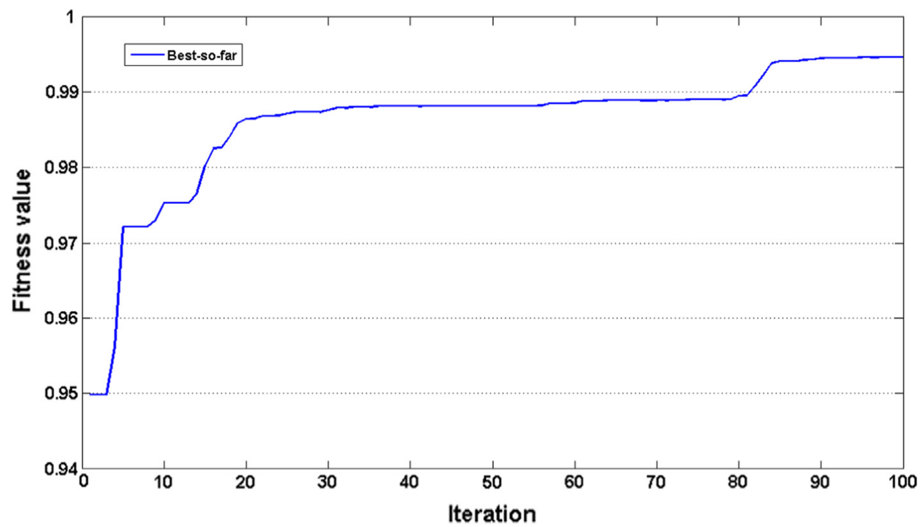

Fig. 8. PSO algorithm convergence curve.

optimization problem with equal weighting values and integrating smart market and PSO algorithm with a 20% increase in fixed loads under G2 contingency, minimum load shedding is derived. Since *LSMP*s of dispatchable loads are high in the case of G2 contingency that may cause a significant *EPNS* cost, no dispatchable load is participated. By solving the multi-objective optimization problem, the revenue and cost of *GENCO* #1 are 2004.9 \$ h^{-1} and 889.94 \$ h^{-1} respectively, while *EPNS* cost is 2063 \$ h^{-1}. Therefore, the loss of *GENCO* #1 is 948.04 \$ h^{-1}. The revenue and cost of *GENCO* #2 are 4884.8 \$ h^{-1} and 2301.59 \$ h^{-1} respectively which leads to a profit 2583.21 \$ h^{-1}. The revenue and cost of *GENCO* #3 are 4117.41 \$ h^{-1} and 1847.96 \$ h^{-1} respectively with a profit 2269.45 \$ h^{-1}. The congestion rent is then 182.487 \$ h^{-1}. Minimum total load shedding that satisfies the multi-objective optimization problem is 29.438 MW which is presented in details in Table 7. In this condition, maximum loadability limit is 542.534 MW. Load cut at each bus of modified IEEE 30-bus test system in the case of G2 contingency is depicted in Fig. 7. The PSO algorithm convergence curve of the multi-objective function in the case of G2 contingency is illustrated in Fig. 8. Comparison of *LMP* before and after contingency of G2 is demonstrated in Fig. 9. As it is shown in Table 7, in the case of G2 contingency, *LMP*s of those buses with a shedding less than $0.5P_{D,i}^{n}$ show an increase about 12 \$ MWh^{-1}, while *LMP*s of those buses with about $0.5P_{D,i}^{n}$ load shedding, is decreased. This fact demonstrates the impact of applying an appropriate optimal load shedding on decreasing *LMP*s at the corresponding bus. However such decrease is endeavored to be controlled through the effective methodology utilized. Economic evaluation of different system conditions for *GENCO*s 1–3 is presented in Fig. 10. In this diagram, all 3 *GENCO*s' revenues, costs, and profits are demonstrated to reveal an analysis of any *GENCO*'s economic evaluation in all system conditions.

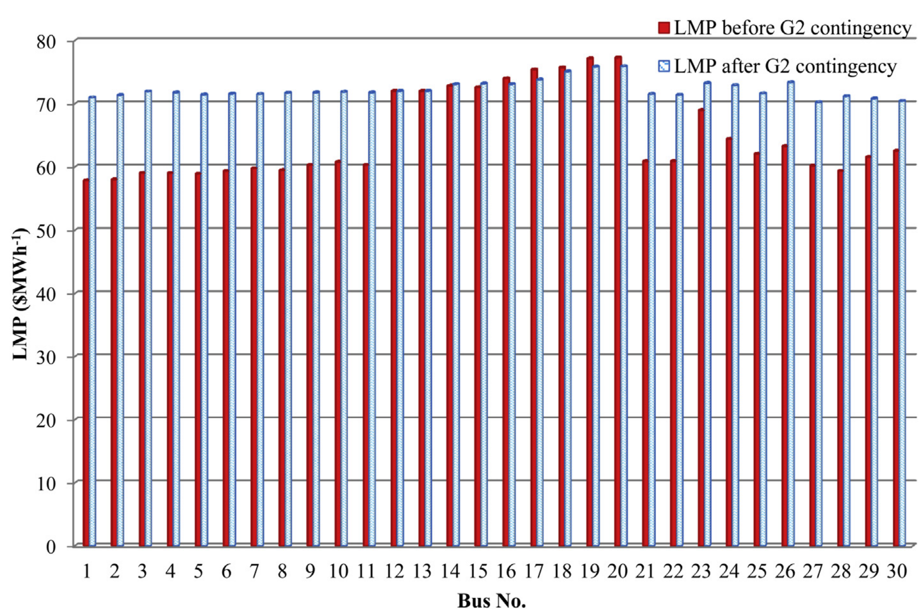

Fig. 9. Comparison of *LMP* before and after contingency of G2.

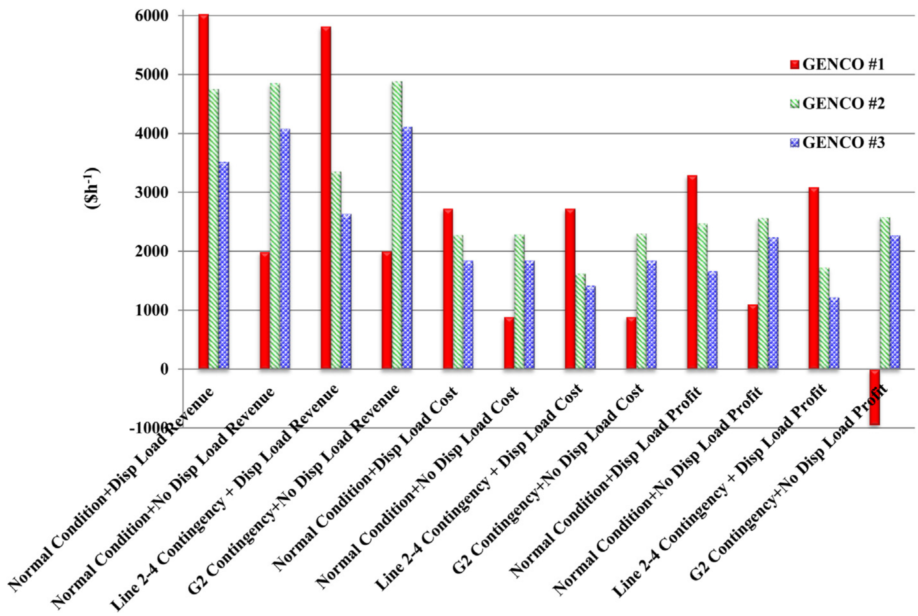

Fig. 10. Economic evaluation of different system conditions for *GENCOs* 1–3.

6. Concluding remarks

Market-driven load shedding considering voltage stability using PSO is discussed in this paper. Restructured power system issues including maximizing social welfare beside voltage stability of the power system are taken into consideration when an outage occurs. A technoeconomic multi-objective function to provide intelligent-based optimal load shedding is presented while the impact of a contingency on different economic aspects of power system is analyzed. The proposed method is executed under the smart market environment of MATPOWER 4.1 where it is applied to both a small 3-bus power system and a modified IEEE 30-bus test system with significant outcomes. The obtained results demonstrate the capability of the proposed method to perform an intelligent-based optimal load shedding with minimum load cuts satisfying maximum social welfare and maintaining voltage stability.

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